Trends in Real Electricity Retail Prices and Bills

PURPOSE

The purpose of this paper is to examine the forecasts of electricity price and consumer bills contained in the Sixth Power Plan. The paper is motivated partially by the contrast between the plan results and one of the main messages adopted by PNUCC that electricity costs are expected to increase. In addition, the focus in the Sixth Power Plan on prices and bills is a new one. Electricity price and bills are not primary objectives of the Council's plan. Their treatment and inclusion in the Sixth Power Plan was in response to Council member and utility requests to address the issue. This paper is therefore meant to provide a better understanding of the results and approach used to address prices and bills in the plan.

PLAN RESULTS

The Sixth Power Plan forecast the average electricity price to increase by less than one half a percent per year in constant-year dollars. Typical residential bills were forecast to decrease by just less than one percent per year. This paper discusses these results at a high level.

Although the term "price" is used in this discussion, the measure is actually average revenue per megawatt-hour, that is total revenue collected from electricity sales divided by total megawatt-hours of sales. Further, the prices and bills discussed are for the average of 750 futures. There are many individual future conditions where the results are quite different than the averages.

Figure 1 shows the average retail price forecasts in question. These are retail prices excluding carbon taxes (or costs of emission permits). If carbon prices were included, scenarios that include carbon pricing would have slightly higher prices, but the general pattern is similar - moderate real price increases. In the "carbon risk" scenario, real electricity prices increase by a total of seven percent between 2010 and 2029, or by about 0.3 percent per year. If general inflation were added to the prices to express them in nominal dollars, the annual rate of increase would be 1.4 percent.

Figure 2 shows the estimated average monthly bills of residential customers in constant 2006 dollars. Bills decrease slightly over time in all but the "no conservation" scenario. The carbon risk scenario has a reak monthly bill reduction of 13.3 percent between 2010 and 2029, or -0.7 percent per year. But if general price inflation is added, bills would actually increase by 0.9 percent per year. Table 1 summarizes the beginning and ending prices and bills in both real and nominal dollars.

Table 1: Prices and Bills for the Carbon Risk Scenario

	Prices-($/MWh)		Bills - ($/Month)	
	Real 2006 $	Nominal $	Real 2006 $	Nominal $
2010	$ 66.96	$ 72.33	$ 82.24	$ 88.84
2029	$ 71.67	$ 106.77	$ 71.34	$ 106.28
Total % Change	7.0 %	47.6 %	(-13.3 %)	19.6 %
Annual % Change	0.3 %	1.4 %	(-0.7 %)	0.9 %

Figure 1

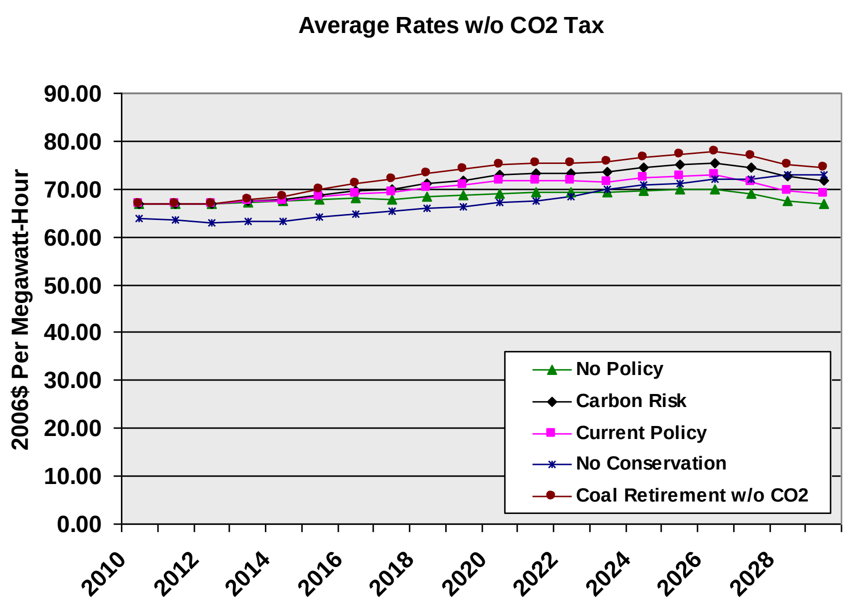
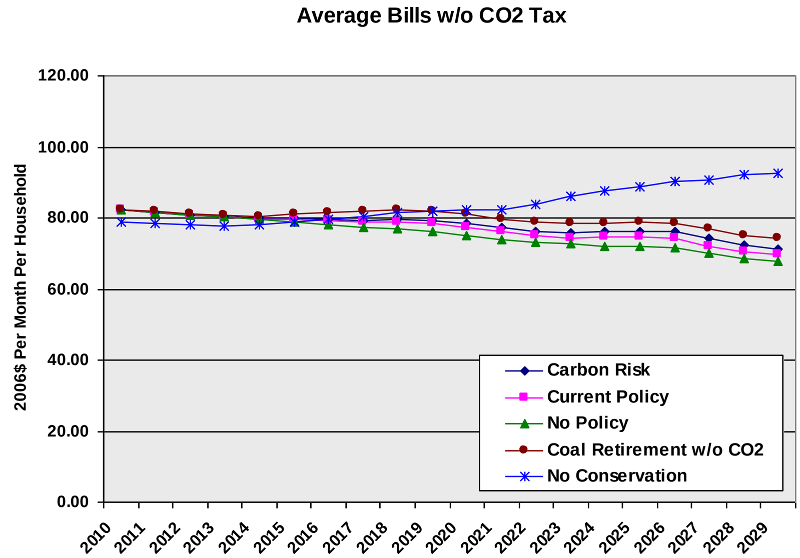


Figure 2



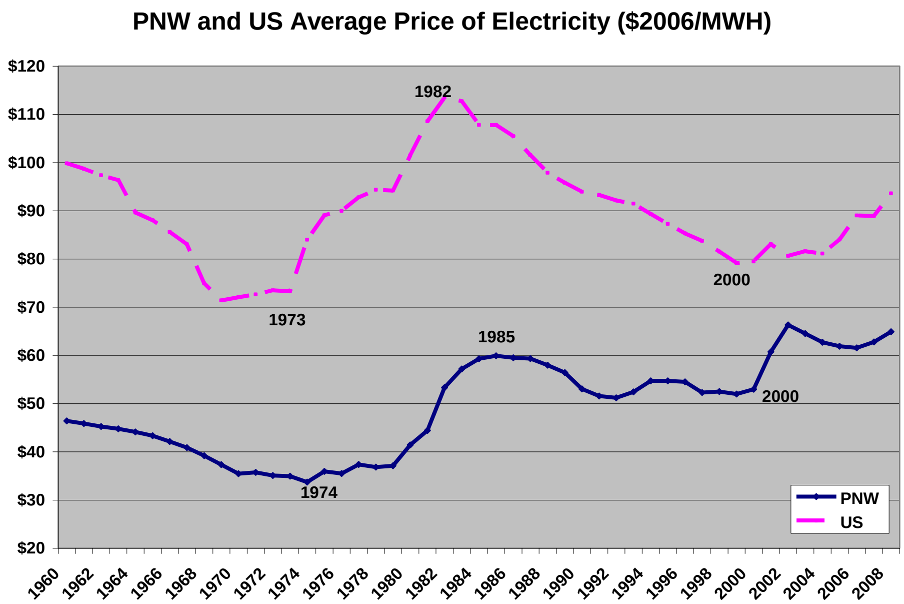
The following discussion examines these forecasts from two different perspectives. The first is relative to historical patterns of prices and how those might relate to bills. The second is to look at patterns of costs for the components of prices and bills to better understand the forces at work behind the forecasts.

HISTORICAL REAL ELECTRICITY PRICES

One indication of whether these retail price (average revenue) forecasts are reasonable is to compare them with historical trends. Figure 3 shows historical average electricity revenues per megawatt-hour for 49 years (1960 through 2008) in the U.S. and the Pacific Northwest. It is evident in the graph that there have been significant periods of declining real prices, some for 20 years. These periods are interrupted by relatively short periods of price escalation. For the U.S., the overall trend is downward for the 49 years. In the Pacific Northwest, constant dollar retail prices increased at a rate of 0.7 percent per year. The region has been characterized, like the nation, by trends of declining real prices interrupted by shorter periods of sharp rate increases.

The causes behind the rate increases are different for the U.S. and the region. In the U.S., the oil embargo in 1973 and the ensuing high oil and natural gas prices were major factors. In the early 2000s, it was a dramatic increase in natural gas prices. For the Pacific Northwest, the increase in the early 1980s was a result of nuclear overbuilding and the WPPSS debt, and the increase in 2000-01 was a result of the western energy crisis, caused by under investment in generating capability combined with a poor water year and a vulnerable market structure.

Figure 3



It is important to note that the Sixth Plan does not assume such precipitating events in the average of the 750 futures. There are such events in individual futures, however. On average, fuel prices increase gradually over time and an adequate power system is maintained. These assumptions, combined with lower load growth and increased low-cost efficiency, are consistent with conditions in which real electricity prices declined historically. In fact, during the 1960s and 1970s, real prices declined significantly in the region, even though loads were growing more rapidly than for the Sixth Plan forecasts.

There is not readily available data on residential bills for this historical period. However, given the historical pattern of average prices, we can infer something about average bills. Factors in the conversion would include household electricity use and how it changes over time. A declining household usage of electricity over time would tend to decrease bills; an increasing use per household would increase bills. Changes in electricity use per customer can reflect changes in lifestyles, efficiency, or fuel choice.

The patterns of changes in these factors are significantly different for the Pacific Northwest than for the nation. As shown in Figure 4, the use of electricity per capita has been flat for 25 years in the Pacific Northwest, while electricity use per capita in the nation has continued to increase. This regional trend may reflect several important factors including a legacy of cheap electricity that resulted in electricintensive industry and building. As electricity has become less cheap in the region, electricity intensive industries have closed or changed fuels, buildings have become more efficient, and natural gas has been substituted for electricity.

Figure 4 illustrates the trends in electricity use per capita for the residential and commercial sectors in the region and the U.S. Figure 5 shows that the electricity share of energy use has remained constant, even slightly declined, while the U.S. share has continued to grow.

Figure 4

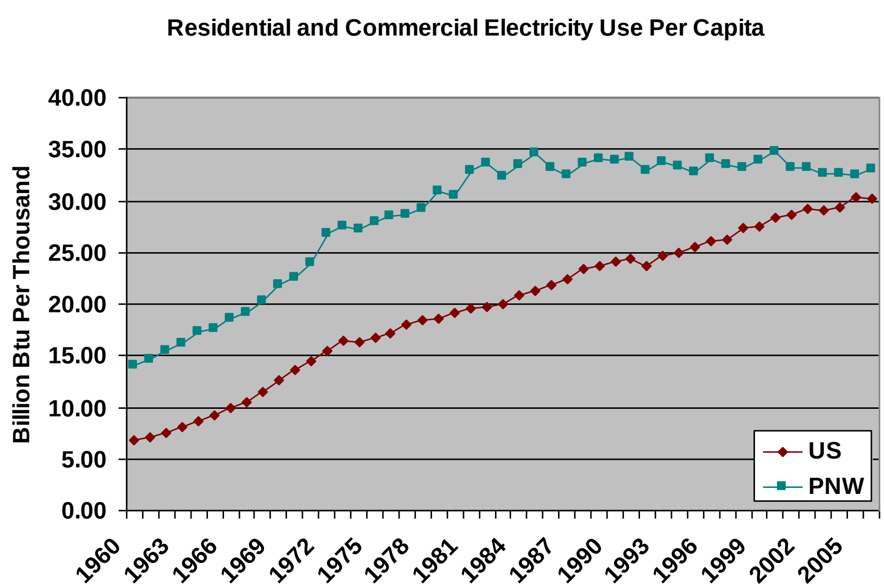
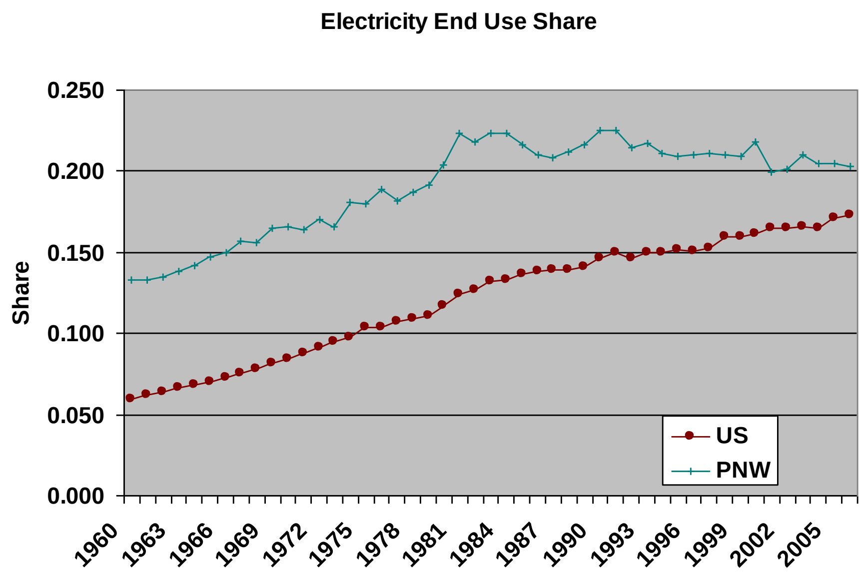


Figure 5



DETERMINANTS OF RETAIL PRICE AND BILLS

Average revenue per megawatt-hour, which is used as a measure of retail price, is simply the total revenue that needs to be recovered through electricity sales divided by the number of megawatt-hours sold or consumed. Increases in revenue requirements will increase both prices and bills if other factors do not change. Increases in sales will decrease average prices if revenue requirements do not change. The definitions are illustrated in the equations below.

$$\text{Electricity Price} = \frac{\text{Revenue Requirements}}{\text{Sales}}$$

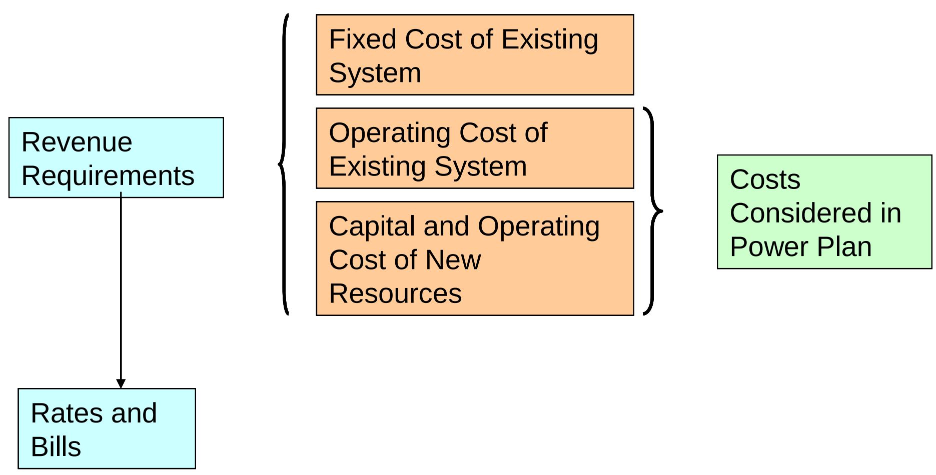
Customer Bill = Electricity Price * Monthly Electricity Use Per Household

The changes in these determinants over time in the Council forecast are discussed below.

Revenue Requirements

Total revenue requirements can be broken into three conceptual components; the fixed cost of the existing power system (generation, transmission and distribution infrastructure), the operating cost of existing generation, and the capital and operating cost of new generating resources and efficiency programs. The Council's power plan and utility IRPs are based on only the forward-going costs. These are the last two components above. The fixed cost of the existing system is not part of the planning objective, but it is part of revenue requirements. These components and their roles are illustrated in Figure 6.

Figure 6



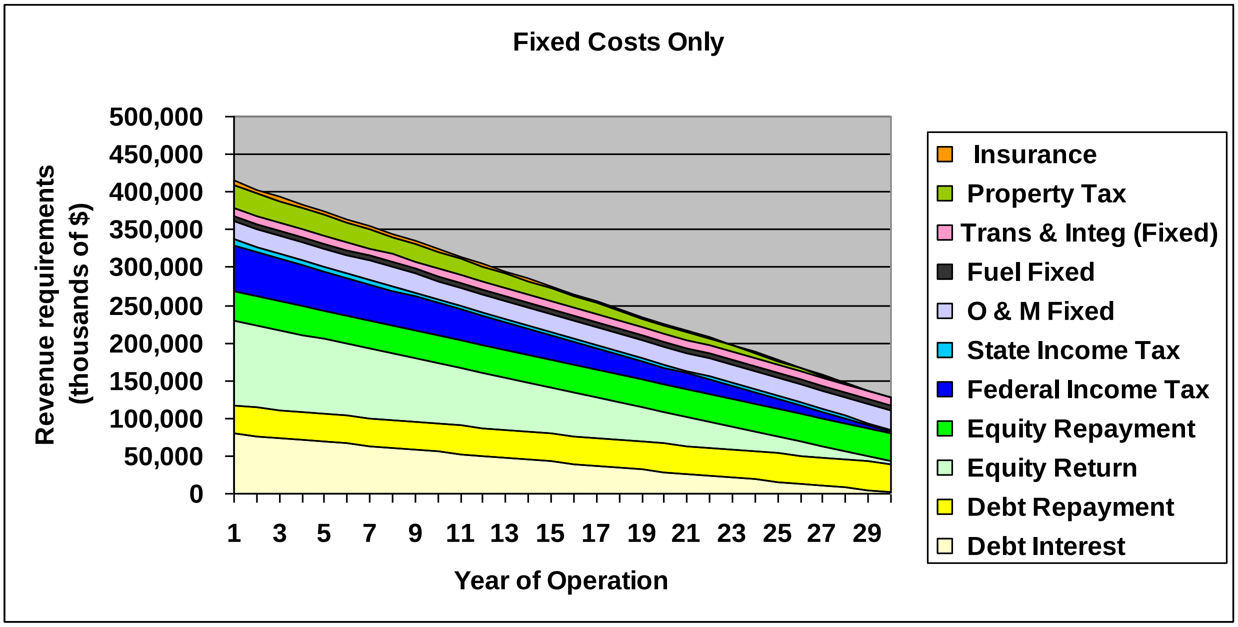
Most of the costs of the last two components are calculated in developing the power plan. The operating cost of the existing system changes over time in real dollars mostly in response to changing fuel costs. The change in the cost of new resources depends on the type of resources developed over time and their costs. The information on these two components of revenue requirements is determined in the power plan analysis with one exception. The plan does not estimate the cost of upgrades and expansions to the transmission and distribution system except for specific generation resources that require additional transmission to reach load centers. An example of transmission cost that is included is the cost of bringing Montana or Wyoming wind power to the load centers in the region.

To estimate prices and bills, the first component of revenue requirements, the fixed cost of the existing system, has to be estimated. We have a pretty good estimate of these costs currently, but little concrete information on how they might change over time. In the calculation of prices and bills for the power plan, these costs of the existing system were assumed to be constant over time in real 2006 dollars.

A large share of these costs is investments in generation, transmission, and distribution equipment. These costs are expected to decline over time in constant dollars for two reasons. First, these investments were made in nominal dollars in the past. The investments, plus interest charges or a return on utility equity, are recovered over time through prices. The capital recovery charges are based in nominal dollar investments and therefore decrease in real dollars over time. A constant nominal dollar amount will decrease in real dollars over time at the rate of inflation, which was assumed to be 1.65 percent per year in the plan. Second, the interest, returns on equity, and related property and income taxes decrease in nominal dollars, and even more in real dollars, as the assets are depreciated.

Figure 7 illustrates how the real dollar costs of a specific resource change over time. The figure demonstrates how the fixed cost of an IGCC coal plant put into service in 2015 changes over time. Over the 15 years of the plant's life, these costs decrease from $415 million to $127 million. Decreasing components include equity return, debt interest, federal and state income taxes, and property taxes.

Figure 7



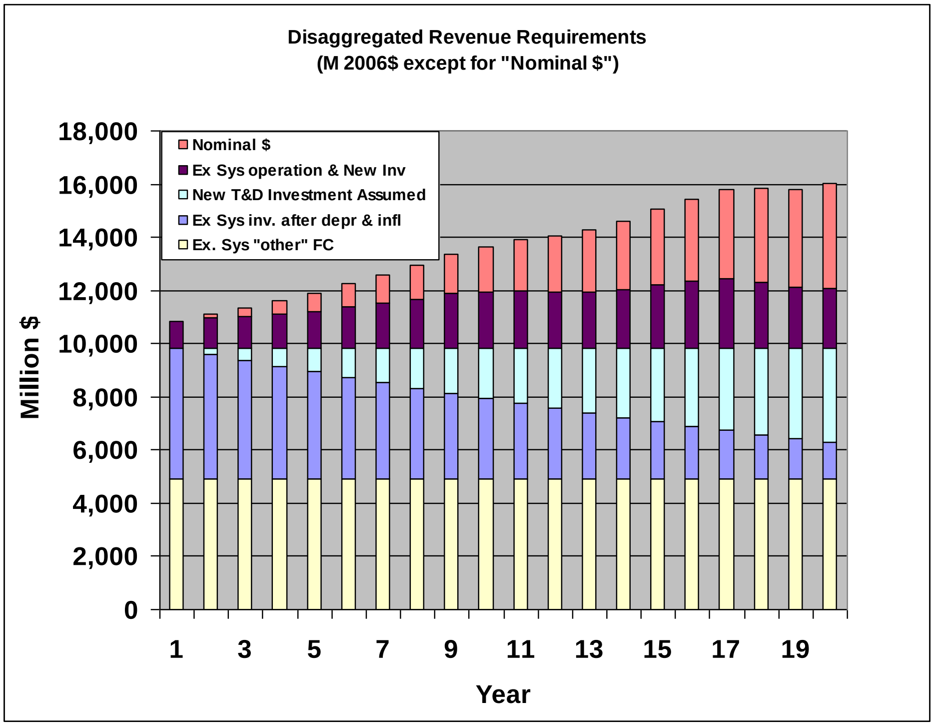
Other components of the cost of the existing system may be related to personnel costs and business overhead. Such costs can generally be assumed to grow with inflation and therefore be constant in real dollars.

Figure 8 puts the fixed costs of the existing power system in the context of Sixth Power Plan. The current fixed cost of the existing system, not counting the operating cost of existing resources, accounts for about 70 percent of all revenue requirements at the beginning of the plan analysis. It is the height of the first three bar segments from the bottom of Figure 8. In calculating revenue requirements for the plan, this $10 billion cost was assumed to be constant in real dollars. If it is assumed that half of the current fixed costs are for plant and equipment that decreases with inflation and depreciation (second bar), the plan assumption provides room for upgrades, replacements and new transmission and distribution investment (third bar), which was not included in the power plan costs.

The fourth bar shows the operating cost of existing resources plus the cost of new resources in the plan. These costs increase over time with fuel costs and as new efficiency and generation investments occur. In the plan, the new resource costs are limited by the fact that conservation, which dominates new resources, is low cost.

The final or top bar segment illustrates the total revenue requirements in nominal dollars. This adds general inflation. Some utilities and analyses present results in nominal dollars. As shown in the graph, inflation changes the appearance of future costs significantly.

Figure 8



Electricity Sales

The change in kilowatt-hours sold over time depends on the growth in customers and changes in the use of electricity per customer. Clearly the use per customer is reduced by efficiency improvements, but also by structural changes in the economy such as the shift from industrial to commercial activities that use less energy or substitution of natural gas for electricity for space and water heating.

Reductions in consumption (kilowatt-hours) tend to raise electricity prices in the short term because there are fewer sales to recover the revenue requirement. But the reduced need for new resources also reduces the growth in revenue requirements in the longer term and therefore reduces prices.

Because prices are equal to the revenue requirement divided by sales, the change in prices over time depends on the relative changes in these two factors. In the Sixth Power Plan, loads before efficiency gains were forecast to grow at 1.4 percent per year. After efficiency gains, however, the load growth rate was only 0.3 percent per year. Revenue requirements were expected to grow at 0.6 percent per year, resulting in some growth of prices.

Customer Residential Bills

As shown above, the change in residential electricity bills over time is equal to the price multiplied by the monthly sales of electricity per household. Although electricity prices are forecast to increase slightly over time, the electricity use per household is predicted to decrease. Between 2010 and 2029, residential electricity use per household is predicted to fall from 13 megawatt-hours to about 9.4 megawatt-hours. This is a 1.7 percent decrease per year. When combined with a 0.3 percent per year real price escalation, the result is declining electricity bills.

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